NON-PUBLIC?: N

ACCESSION #: 8905190516
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Sequoyah, Unit 2 PAGE: 1 OF 10

DOCKET NUMBER: 05000328

TITLE: Three Unit 2 Reactor Trips Due To Low-Low Steam Generator Level Which Occurred During The Startup Following The Unit 2 Cycle 3 Refueling Outage
EVENT DATE: 04/15/89 LER #: 89-005-00 REPORT DATE: 05/11/89

OPERATING MODE: 1 POWER LEVEL: 030

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION
50.73(a)(2)(iv)

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COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE TO NPRDS:

SUPPLEMENTAL REPORT EXPECTED: NO EXPECTED SUBMISSION DATE:

ABSTRACT:

This report details three unit 2 reactor trips which occurred on April 15, 16, and 19, 1989 following the completion of the unit 2 cycle 3 refueling outage. For all three events operator actions (performed in accordance with plant procedures) caused steam generator (SG) water levels to begin fluctuating and, subsequently, a reactor trip due to low-low water level in one of the SGs. For the April 15 event, unit 2 was at 30-percent reactor power and in the process of performing a main turbine overspeed test when the reactor tripped due to low-low water level in SG No. 4. For the April 16 event, Operations was in the process of performing a swapover from auxiliary feedwater (AFW) to main feedwater (MFW) supply to the SGs when the reactor tripped due to low-low water level in SG No. 1. For the April 19 event, during normal power escalation (18-percent reactor power), Operations was in the process of swapping over from the MFW bypass valves to the MFW main regulating valves when the reactor tripped due to low-low water level in SG No. 2. The April 15 cause was allowing SG level conditions to degrade (wide swings) to where

recovery was extremely difficult, before terminating nonessential activities, discussing alternative methods of level control, and regaining control of plant conditions. The April 16 cause was an out-of-calibration condition on 2-PT-3-1 (MFW pump discharge pressure). The cause for the April 19 trip was operating loops 1 and 2 bypass valves in manual and not allowing sufficient time for the system to stabilize after each transient. Numerous corrective actions are planned to be taken as detailed in TVA's letter to the NRC dated May 5, 1989.

END OF ABSTRACT

DESCRIPTION OF EVENTS

This report details three reactor trip events: one on April 15 (from approximately 30-percent reactor power), one each on April 16 and April 19, 1989 (both from approximately 18-percent reactor power).

APRIL 15, 1989

On April 15, 1989 with unit 2 in mode 1 (30-percent reactor power, 2230 psig and 553 degrees F), a reactor trip occurred at 0009 EDT. The trip resulted from a low-low level setpoint (18 percent) in steam generator (SG) No. 4 (EIIS Code SB) being reached.

At 1847 EDT, on April 14, 1989, unit 2 attained 30-percent rated thermal power (RTP) with control rod bank D (EIIS Code AA) at 152 steps. At 2156 EDT, postmaintenance testing was completed on main feedwater pump (MFWP) "B" (EIIS Code SJ). MFWP "A" was inservice and in automatic at this time and adequately controlling the resultant flow and speed fluctuations to maintain proper SG levels. The main steam dump valves (EIIS Code SB) were placed in the pressure control mode at 2209 EDT, to prepare for a decrease in turbine/generator power in accordance with system Operation Instruction (SOI)-47.2, "Main Turbine Overspeed and Oil System Test - Units 1 and 2," as required by General Operating Instruction (GOI)-5," Normal Power Operation - Units 1 and 2." As turbine power is decreased, the steam dump system would increase the amount of steam bypassed to the condenser, thus allowing reactor power to remain constant. At 2211 EDT, the operators began decreasing generator load (turbine power) while holding reactor power steady at 30 percent. During this decrease it was noticed that feedwater flow began fluctuating, and at 2220 EDT, MFWP "2A" was placed in manual control in an attempt to dampen the 250 revolutions per minute (rpm) oscillations that were occurring. The change in turbine impulse chamber pressure due to the decrease in load caused the SG level program to decrease the target level from 44 to 33 percent. Normal SG level for 30-percent reactor power is 44 percent. At 2344 EDT, the unit 2 generator was removed from the grid to begin turbine overspeed testing. It was then noticed that the SG No. 3 level control valve (LCV) (EIIS Code SJ) was not responding properly to the steam flow/feed flow indicators and was subsequently placed in manual control. At 2348 EDT, the turbine (EIIS Code TA) tripped on overspeed (1910 rpm) as required by SOI-47.2 (first of two overspeed trips required). During turbine acceleration for the second overspeed test, SOI-47.2 was suspended due to SG level fluctuations. Due to the complexity of the situation and the problems the unit 2 unit operators (UOs) were having stabilizing SG levels, the shift operations supervisor (SOS) instructed a more experienced UO from unit 1 to assist in the recovery of stable SG levels on unit 2.

The LCVs for SG Nos, 1, 2 and 4 were still in automatic, and MFW "2A" speed control, along with the LCV for SG No. 3, were in manual when the unit 1 UO arrived and took control. SG No. 3 level reached its high setpoint at 60 percent which caused a feedwater isolation on loop 3. The unit 1 UO allowed the SG No. 3 level to decrease below the setpoint and manually matched the steam flow and feed flow. Almost immediately after recovering from the feedwater isolation on loop 3, the SG No. 4 level reached its low-low level setpoint of 18 percent, causing a reactor trip at 0009 EDT, on April 15, 1989.

APRIL 16, 1989

On April 16, 1989 at 0048 EDT, unit 2 was in the process of placing MFWPs in service when a reactor trip occurred due to low-low water level experienced in SG No. 1.

Prior to this event, the evening crew initiated GOI-2, "Plant Startup From Hot Standby to Minimum Load," and had completed rolling of MFWP "B". The midnight crew continued with unit startup in accordance with GOI-2 after a review of plant status and equipment operations was completed following shift turnover. Plant conditions at the start of this event included reactor power at approximately 1-1/2 percent as indicated on Nuclear Instrumentation NR-45 (EIIS Code IG), SG levels controlled by auxiliary feedwater in automatic, MFWP "B" in manual operation, and pressure transmitter (PT) -3-1 indicating high (although not known by the operator). The plan for power escalation consisted of performing a swapover from auxiliary feedwater (AFW) to main feedwater (MFW) by placing the bypass feedwater regulator in automatic. At approximately 0030 EDT, the bypass regulator valves were placed in automatic. The first indications of a SG level transient were noted when AFW level control valve 2-LCV-3-148 opened to deliver flow to SG No. 3 concurrent with MFW bypass regulating valve 2-LCV-3-90A in automatic control and opened to approximately 60 percent. However, level in SG No. 3 reduced due to an inadequate amount of feedwater flow to the SGs. In order to control the reduction of level in the loop SG No. 3, operators took action to isolate SG blowdown to loop No. 3 while control rod bank D were withdrawn two steps out of the core to provide for SG level swell and thus allow time for MFW bypass valves to control SG levels. A rapid transient followed which resulted in all four SG levels fluctuating and, ultimately, a reactor trip from low-low SC level on loop No. 1. During this transient, the reactor Nuclear instrumentation System power was increased to approximately 18 percent prior to the reactor trip. This power escalation was a result of the balance of plant (BOP) operator's request for increased power in an attempt to compensate for the decrease in SG level by the ensuing SG swell. At this point in the event, a decision was made by the BOP operator that a power reduction would most likely have led to a loss of SG level. This power increase was monitored by the lead UO and assistant shift operation supervisor (ASOs), and attempts were made to minimize this escalation.

APRIL 19, 1989

On April 19, 1989 at 0447 EDT, unit 2 was in the process of power escalation (mode 1, 1.9 percent reactor power, 2154 psig and 552 degrees F) when a reactor trip occurred due to low-low water level experienced in the loop No. 2 SG.

Prior to this event, the operations evening crew were performing GOI-2, and had placed the MFW system in service using MFWP "A". Following the shift turnover and a review of the plant status and equipment operations, the midnight crew continued with the unit startup in accordance with GOI-2. The decision was made to increase reactor power slowly (one-half percent step increments every 90 seconds) to minimize fluctuations in SG water level.

MFW flow to the SGs was through the MFW bypass valves with all four valve controllers in automatic. Upon reaching approximately 4-percent reactor power the UO noticed the MFW bypass valve for loop 1 was not maintaining a steady level in SG No. 1 (level was decreasing). At the direction of the ASOS, the controller was placed in manual. The level in loop No. 1 settled out, and the decision was made to continue startup according to the GOI.

At 0145 EDT, unit 2 entered mode 1 (5-percent reactor power) and at 0245 EDT, the P-10 permissive was initiated. When reactor power reached approximately 10 percent, the loop 2 MFW bypass valve began swinging divergently and, with the permission of the ASOS and the SOS, the UO placed this controller in manual. At this point, both loop 1 and loop 2 MFW bypass valve controllers were in manual and the remaining two controllers were in automatic. MFW flow was steady and the decision was made to continue startup according to the GOI.

At 0300 EDT, the main turbine was latched and ready to roll to 1800 rpm. MFWP "A" master controller was placed in "Auto", at approximately 15-percent reactor power, which deviates from GOI-2 (requires the controller to be in "Manual"). With feedwater bypass valves approximately 60 percent open, the operator attempted to transfer to the MFW regulating valves. Due to SG level fluctuations, the MFW regulating valves were closed, and Operations personnel waited for the feedwater flow to stabilize on the bypass valves. Reactor coolant system (RCS) dilution was begun at 0413 EDT to increase power.

At approximately 18-percent reactor power, and after SG levels were stabilized, another attempt was made to open the MFW regulating valves. Loops 3 and 4 MFW regulating valves were opened, and the bypass valves were able to maintain this level in automatic. When it was attempted to open loops 1 and 2 MFW regulating valves, SG levels started swinging on loops 3 and 4. Divergent oscillations began on all four SGs and the operators were unable to bring the oscillations under control. At this time, MFWP "A" was placed in manual to maintain a steady feedwater flow and prevent pressure fluctuations (delta P across the MFW regulating valves).

The level oscillations continued, and several partial feedwater isolations occurred on loops 1, 3, and 4. On the fourth l
vel swing for SG No. 3 a
partial feedwater isolation occurred, and the SG level continued to swell to greater than 75 percent. At 0444 EDT, the MFWP tripped due to a high-high level in SG No. 3. The operator immediately began to manually step in the control rods in an effort to prevent a reactor trip. Since Operations personnel were unable to reset and restart the MFWP quickly enough, the reactor tripped on low-low SG level. At 0447 EDT, the reactor tripped at 1.9-percent reactor power due to a low-low level in SG No. 2. The conditions at the time of the trip were that loops 1 and 2 MFW bypass valves were in manual, loops 3 and 4 MFW bypass valves were iii automatic, and MFWP "A" was in manual.

After each of the reactor trips detailed in this report, Operations personnel responded to safely recover the unit from the transients using emergency procedures E-0, "Reactor Trip or Safety Injection" and ES-0.1, "Reactor Trip Response".

Following the April 19 reactor trip, management put together a task force to establish requirements to be executed prior to and during unit 2 startup. A unit 2 startup action plan was developed which identified immediate and longer-term corrective actions.

CAUSE OF EVENTS

APRIL 15, 1989

The immediate cause of the reactor trip on April 15, 1989, was a low-low level in SG No. 4. The low-low level condition was caused by perturbations in the feedwater flow and SG levels while attempting to recover from a feedwater isolation on loop 3. Some contributing causes of this event were:

1. MFWP "2A" was required to be placed in manual control due to excessive rpm swings.

2. Loop number 3 LCV was placed in manual due to abnormal responses.

3. GOI-5, "Normal Power Operation - Units 1 and 2," allowed the use of the MFW regulating valves in automatic which maintained SG levels at 33 percent while reactor power was 30 percent, which normally corresponds to a SG level of 44 percent.

The root cause of the April 15, 1989 event, was that the Operations team allowed SG level conditions to degrade (wide swings) to a point where recovery was extremely difficult before terminating all other nonessential activities, discussing alternative methods of level control, and regaining stable control of plant conditions.

APRIL 16, 1989

The cause of this event is attributed to an out-of-calibration condition 2-PT-3-1 (MFWP discharge pressure). This PT provides a reference signal to the main feed pump speed control circuitry. This PT was found to be reading approximately 60 pounds per square inch (psi) higher than it should. In this condition, the MFWP was not being controlled at a speed to provide adequate MFW flow. Thus, in the attempt to take auxiliary feedwater out of service, the reactor ultimately received a reactor trip signal on low-low SG water level.

APRIL 19, 1989

During startup, Operations identified that the MFW bypass valves for loop 1 and loop 2 would not maintain SG level in automatic and placed the controllers in manual. SG levels stabilized, and Operations made the decision to continue startup with the controllers in manual as opposed to stopping and correcting the problem(s) with the controllers.

During the swapover from MFW bypass valves to MFW main regulating valves, both loop 1 and loop 2 MFW bypass controllers were in manual, and the remaining two loop controllers were in automatic. Loop 3 and loop 4 MFW main regulating valves were opened slightly, and the swapover began from the bypass valves, with SG levels being successfully maintained, When it was attempted to open loop 1 and loop 2 MFW regulating valves, SG levels began swinging on loop 3 and loop 4. Subsequently, all four SG levels began fluctuating, and the operators were unable to bring the oscillations under control. All four MFW bypass valve controllers being in automatic would have decreased the number of parameters the operators were having to monitor and, based on the successful swapover on loops 3 and 4, may have prevented the excessive SG level oscillations which eventually lead to the reactor trip.

A review of the Sequoyah startup sequence by a Farley Nuclear Plant Operations representative identified that our startup activities did not allow adequate time for plant conditions to sufficiently stabilize prior to initiating the next startup action.

TVA conducted a review of 11 reactor trips that have occurred at the Sequoyah units since restart. The review addressed five unit 2 restart reactor trips, three unit 1 reactor trips, and three unit 2 cycle 4 startup trips. The general results indicated that nine reactor trips involved feedwater. Five of the nine reactor trips involved full or partial feedwater interruptions that were caused by testing, maintenance, or equipment failures. Four of the nine reactor trips involved feedwater control problems during startup. TVA concluded that six of the feedwater-related reactor trips have relevant similarities.

Four common elements were identified during further review of the six similar reactor trips (which included the three trips discussed in this report). One common element was an Operations philosophy that accepted known equipment problems. Several startups were attempted with feedwater bypass valve controller problems. The second common element involved the fact that dynamic tuning was not performed for the feedwater bypass valves during all startup attempts. A third common element was the fact that the standard startup methods were not specific or correct for all feedwater control transfer evolutions. The procedures allowed either manual or automatic bypass valve control without specific guidance. The procedures incorrectly allowed automatic main valve control during turbine load reductions below 20-percent turbine power. The fourth common element involved insufficient follow-through on previous posttrip recommendations on feedwater controls. TVA did not take advantage of lessons learned from the unit 1 startup experience. Feedwater bypass valve tuning was not formally integrated into the startup process. The standard startup method was not completely proceduralized in the manual bypass valve control was routinely used without specific guidance.

Several contributing factors were identified that affected Operations performance. In some cases, there was a willingness to proceed with material deficiencies. Operating procedures contained some generalities that allowed excessive alternatives for feedwater operation. The team approach to plant evolutions was applied inconsistently. Preparations for plant evolutions are generally slow and methodical; however performance becomes rushed at times.

Overall, restart proceeded with minimal outstanding equipment deficiencies. For example, the number of outstanding control room work orders (12) was the lowest in Sequoyah unit 2 history and well below the startup goal of 20. However, feedwater system discrepancies identified during startup were not worked expeditiously and corrected prior to proceeding with power escalation. TVA also found that the feedwater bypass valve dynamic calibration methodology to support power escalation did not reflect current industry experience.

As a result of the reactor trips, TVA reviewed the design of the feedwater system. No outstanding design deficiencies were identified that required resolution prior to restarting unit 2. In particular, TVA performed an evaluation of differences between the analog feedwater bypass controller used for unit 2 and the digital feedwater bypass controller used for unit 1. From an engineering with the overall system response time, which is dominated by the mechanical/pneumatic valve interface. Westinghouse Electric Corporation performed an independent evaluation of controller differences and did not recommend one controller over the other. There was no overriding operator preference for either controller.

ANALYSIS OF EVENTS

All three events detailed in this report (April 15, April 16, and April 19, 1989) are being reported in accordance with 10 CFR 50.73, paragraph a.2.iv, as automatic actuations of the engineered safety features actuation system (ESFAS) and reactor protection system (RPS).

For all three events, the safety-related RPS logic performed as designed to mitigate the consequences of the SG low-low level condition by causing a reactor trip (reactor trip breakers opened and all control rods dropped to bottom position). If an actual postulated safety analysis accident had occurred to cause the SG low-low level condition, the reactor would have shutdown as designed, Therefore, none of the events detailed in this report caused the safety of the plant or public to be compromised.

CORRECTIVE ACTIONS

The following corrective actions were identified to the NRC during an April 23, 1989 meeting concerning unit 2 reactor trips that occurred on April 15, 16, and 19, 1989 and followed up with a summary letter to the NRC dated May 5, 1989.

Prior to restarting unit 2, TVA revised GOI-2 to incorporate industry feedwater startup experience, add guidelines for each crew member, control the use of manual bypass control, add cautionary statements prior to important feedwater evolutions, and add hardware operability requirements for important feedwater evolutions. Two special startup crews were selected and trained on the new startup methods. These crews were used for the unit 2 feedwater startup methods. To ensure that all normal crews become proficient at the standard startup methods, TVA will incorporate the standard feedwater startup method into certification training and requalification training. TVA will also add specific training on control loop design and operation into the certification training and requalification training. TVA also will review operating procedures to incorporate team concepts or test director requirements for important, critical tasks.

TVA has a number of activities planned to improve the Operations philosophy at Sequoyah.

1. TVA will revise Administrative Instruction (AI)-30, "Nuclear Plant Conduct of Operation," to identify the role of senior operations management support in the main control room during important plant evolutions.

2. TVA will develop specific management requirements to reinforce the desired operational philosophy.

3. TVA is developing a long-range plan to get Operations management more involved with industry top performers and Institute of Nuclear Power Operations evaluations.

Several maintenance program enhancements are planned to improve performance. TVA developed a dynamic calibration methodology for feedwater controls, incorporating industry experience, prior to restarting unit 2. TVA provided feedwater flow indication over the full range and installed temporary enhanced SG level recorders prior to restarting unit 2. To ensure proper preparation of the feedwater system for startup from future refueling outages, TVA will establish a comprehensive checklist of feedwater equipment cheeks, calibrations, and testing activities for the unit 1 cycle 4 refueling outage.

TVA is conducting a number of feedwater system studies to identify areas for improvement. A multidiscipline review (Nuclear Engineering, Operations, and Maintenance) will be conducted of the integrated feedwater control system. This review will also include a human factors review. A study will be done of the main feed pump turbine speed control system. A study of the main feedwater control valve and bypass valve flow characteristics will be done. The results of these studies will be reviewed by TVA management, and the results will be submitted to NRC.

TVA has identified a number of engineering changes that affect feedwater system performance. Prior to restarting unit 2, TVA revised the main feed pump setpoint program to improve low-power control characteristics and change the control point for manual bypass valve control to increase the operating margin to the trip setpoint. TVA will standardize the feedwater bypass valve controllers by startup after the unit 2 cycle 4 refueling outage. TVA will install human factored, enhanced SG level recorders for startup feedwater control by startup from the cycle 4 refueling outage for each unit. TVA will install the Eagle 21 protection set by startup from the cycle 4 refueling outage for each unit. Also, TVA will install the Westinghouse Owners Group startup trip reduction package (SG setpoint trip time delay and environmental allowance modifier) by startup from the cycle 5 refueling outage for unit 1 and the cycle 4 refueling outage for unit 2.

ADDITIONAL INFORMATION

TVA conducted a review of reactor trips that have occurred at Sequoyah since unit 2 restarted from a prolonged shutdown, and TVA concluded that six feedwater related reactor trips have relevant similarities. The six reactor trips with relevant similarities encompasses the three trips being reported on this LER along with two trips reported on SQRO-50 328/88028 and one trip reported on SQRO-50 327/88047.

COMMITMENTS

Commitments were identified in the April 23, 1989 meeting with the NRC concerning unit 2 reactor trips that occurred on April 15, 16, and 19, 1989 as summarized in TVA's letter to the NRC dated May 5, 1989.

0265R

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May 15, 1989

U.S. Nuclear Regulatory Commission
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Gentlemen:

TENNESSEE VALLEY AUTHORITY - SEQUOYAH NUCLEAR PLANT UNIT 2 - DOCKET NO. 50-328
- FACILITY OPERATING LICENSE DPR-77 - LICENSEE EVENT REPORT (LER) 50-328/89005

The enclosed licensee event report provides information concerning three unit 2 reactor trips due to low-low steam generator level which occurred during startup following the unit 2 cycle 3 refueling outage. This event is being reported in accordance with 10 CFR 50.73, paragraph a.2.iv.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

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